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Feasibility of Reproduction of Stored CO_2 from the Utsira Formation at the Sleipner Gas Field

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Abstract

The feasibility to recover stored CO_2 from the Utsira formation at Sleipner has been studied by reservoir simulation of a 15 years injection (until 2011) and a subsequent scenario where the CO_2 is produced from a horizontal well under the cap rock. There are three important aspects related to the recovery of the stored CO_2:

- Performance of temporary storage of CO_2 for EOR purposes.
- Reproduction of mobile CO_2 from formations that turn out to be less suitable for storage than anticipated.
- The reproduction simulation can resemble an open leaking well.

The simulations are based on experimental drainage and imbibition curves for the corresponding injection and production phase. The results show that until 47.7 % of injected CO_2 can be reproduced during a seven year non-stop production period. The results are based on a 15 year injection period, an irreducible water saturation of 5 % and a residual CO_2 saturation after imbibition of 25 %. Also the amount CO_2 reproduced was found to be increasing with decreasing values of irreducible water saturation.

Data from pre-injection seismic, well logs and petrophysical data are used to build a reservoir model. The Utsira formation is intersected by thin horizontal discontinuous shale layers that impede the vertical migration and cause entrapment of the CO_2 in flat plumes. The transport properties of these shales are obtained by history matching the size of the plumes observed from seismic monitoring. To accommodate the necessary amount of CO_2 the lateral size of the model had to be 5.2 km x 7.9 km. To minimize numerical dispersion a relatively fine grid was required giving 2.1 million grid blocks in the model.

The CO_2 plume may be reached by a new well from the Sleipner A platform or through a sidetrack of the existing CO_2 injection well and convert it to a producer. Placement of the producer is optimized for maximum reproduction by utilizing the local topography of the top seal. A producer could be drilled to avoid penetration of the cap-rock close to or above the CO_2 plume and thereby avoid a potential leakage point after abandonment. The formation is high-permeable and relatively flat. The injected CO_2 will therefore accumulate in thin plumes with large lateral extensions. Accordingly, recovery efficiency is low and the formation is less suitable for reproduction of CO_2 compared to formations with a significant dome seal or dipping structures sealed by

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faults. The results give an important confirmation that it is possible to reproduce a significant amount of the mobile CO_2 as a remediation option if a serious lack of integrity of the cap rock is detected.

Keywords: Storage of CO_2; Reservoir simulation; Production of CO_2; CO_2 plume migration

1. Introduction

The Sleipner gas condensate field is located 250 km offshore the west of Stavanger, Norway in the block 15/9. The gas in one of the structures (Sleipner Vest) is containing 9% CO_2 and has to be separated form the export gas to meet quality specifications. Until then the standard engineering practice had bee to vent separated CO_2 into the atmosphere. As a result of a growing concern about the risk of climate change due to emissions of greenhouse gasses the Norwegian government introduced in 1991 a CO_2 tax. As consequence Statoil, who was operating the field, deiced that the CO_2 should be injected into the Utsira Sand. This is a major saline aquifer of late Miocene or early Pliocene age. CO_2 is injected with a deviated well, near-horizontal at the injection point 3000 m from the platform at a depth of 1012 m bellow msl about 200 m below the reservoir top. Injection started when the production from Sleipner Vest started in 1996, by mid 2008 more than 10 million tonnes (Mt) had been injected.

Oilfields are present in the vicinity of the Sleipner gas field with possibility to use CO_2 for enhanced oil recovery (EOR) purposes. The feasibility to use the already stored CO_2 as injection gas is therefore of an interest. From well logs and cores samples it has been shown that the reservoir consists of isotropic high permeable sand with thin imbedded horizontal shales. Previous studies of CO_2 injection in Utsira shows that the injected CO_2 accumulates in thin plumes under the semi-permeable shales (Figure 1). Some of the CO_2 dissolves in the brine and this CO_2 will not be subject to reproduction since it will not be possible to depressurize the large formation significantly. The average reservoir is close at initial hydrostatic pressure.

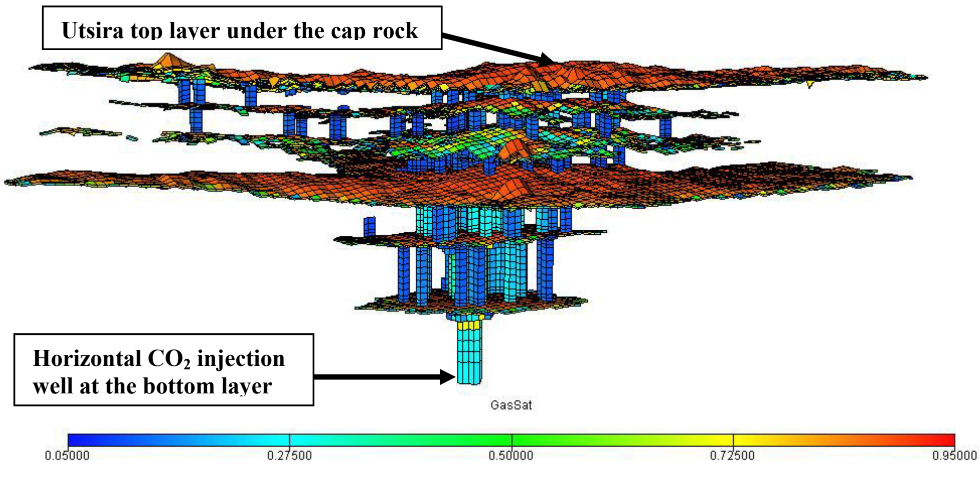

Figure 1 Migration paths and extension of the CO_2 plumes under the shale layers in the Utsira reservoir simulation grid as of year 2011. Only the CO_2 saturation (GasSat) is shown as extracted from the grid. The injected CO_2 enters Utsira through a horizontal well perforated at the bottom.

When CO_2 is injected in an aquifer, water is assumed as the wetting phase to gas (Mo and Akervoll, 2005). Thus the CO_2 is flowing in most parts of the reservoir in a drainage process requiring only a small saturation to mobilize the CO_2. However, when the scenario is extended to describe back-production of stored CO_2, water encroachment will occur as an imbibition process, decreasing the CO_2 saturation around a producer. Behind the advancing water front a considerable CO_2 saturation is left immobile in larger pores due to capillary trapping (Spiteri *et al*., 2005).

Critical gas saturations are therefore considerably higher during imbibition compared with drainage, and hence, using a single set of SCAL curves in modeling an injection and production scenario would lead to overestimate back-production of CO_2. Moreover, additional hysteresis for modeling tertiary flow could also have an impact (Killough, 1976). In this work the effects of using directional dependent multiphase flow data, which are based on laboratory experiments are investigated. Also water cresting along the horizontal well below a thin plume of CO_2 will typically be a challenge.

2. Reservoir simulation input parameters

Porosity, permeability and drainage relative permeability of the CO_2/brine/rock system has previously been measured on Utsira core samples in the SINTEF Petroleum Research laboratory in the SACS project (Lindeberg *el al.,* 2000). The imbibition process relative permeability functions are determined by the steady-state method to resemble the process of water re-entering the reservoir volumes occupied by the injected CO_2 as long as the CO_2 is reproduced (Akervoll and Lindeberg, SINTEF report 2007). The residual CO_2 saturation after water imbibition, S_{rgimb}, is determined as the end-point saturation of this process. Typical value is $S_{rgimb} = 0.30$ for sandstones (Spiteri *et al.,* 2005, Hamon et al. 2001, Holtz, 2002).

The CO_2/brine drainage and imbibition relative permeability curves used in a series of simulations are presented in Figure 2. The end-point water saturation in the drainage process is $S_{wi} = 0.05$ and the residual gas saturation value, $S_{rgimb} = 0.24$, is measured for the Utsira sand in an imbibition process.

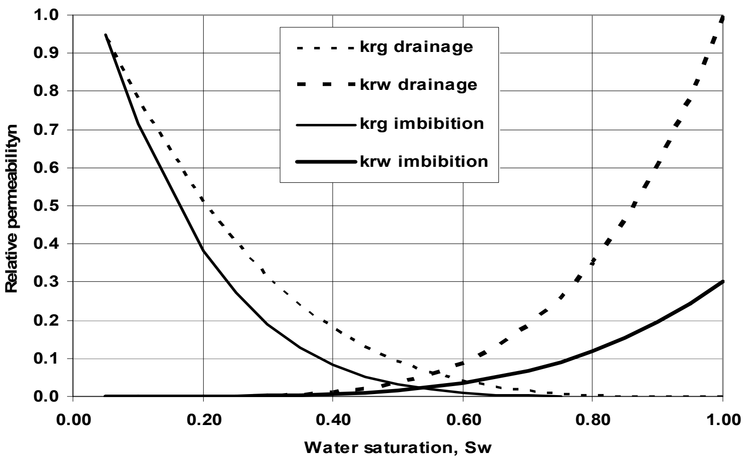

Figure 2 Relative permeability curves for the CO_2/water system in the Utsira sand.

The properties of Utsira saline water containing dissolved CO_2 and the properties of CO_2 at Utsira temperature and pressure are presented in Table 1. The temperature of 31.5 °C and a pressure of 80 bar resemble the conditions at the top layer in the reservoir simulation model. The viscosity of CO_2 has been taken from Vukalovich and Altunin

(1968). The density of CO_2 has been matched with an advanced equation of state by Span and Wagner (1996). Solubility data for CO_2 in brine has been summarized by Enick and Klara (1994). They have fitted a number of experimental data to an extended version of Henry's law. This model provides the basis for dissolution data. Density of the resulting solutions is based on the apparent partial molar volume of CO_2. A correlation (Garcia, 2001) for the partial molar volume of CO_2 is being based on 53 measurements from different authors. The content of water in the CO_2 phase is neglected in black-oil simulations after comparing runs with this option active and without.

Table 1 Properties of Utsira saline water and CO_2 at 31.5 °C and 80 bar (reservoir conditions).

Parameter	
Density of brine, g/l	1.019
Viscosity of brine, mPas	0.772
Solubility of CO_2 in Utsira brine, mmole fraction	20.328
Density of CO_2 saturated brine, g/l	1.028
Viscosity of CO_2 saturated brine, mPas	0.852
Formation volume factor of CO_2 saturated brine (28.2 Sm^3 CO_2/Sm^3 brine)	1.043
Density of CO_2, g/l	0.667
Viscosity of CO_2, mPas	0.051

3. Reservoir simulation model

A reservoir simulation model of the Utsira formation is established big enough to accommodate all of the injected CO_2 until 2011 and beyond. The model is populated with rock and flow property data from the from laboratory core measurements (Akervoll and Lindeberg 2007). The area of the model was 41 km^2 (5.160 x 7.931 km) and approximately 200 m thick. Five intra-sand shale layers were modeled as tight layers with stochastically distributed holes to the mimic the non-continuous properties of the shales that can be observed on well logs. The conductivity of the shale layers were tuned so that the CO_2 accumulating under the shales resembled the major CO_2 accumulations observed on the time-lapse seismic and that the vertical migration rate was similar to the observed rate (it took three years for the injected CO_2 to reach the top seal). CO_2 was injected in the bottom of the formation and the shale layers impede the vertical migration and CO_2 to spread laterally.

The numerical grid contains 150 x 225 x 72 grid blocks in the x, y and z direction. The lateral size of each grid block was 34.4 m x 35.25 m and the height was modelled by 72 layers. The thickness of the layers varied form 0.8 m below each shale to 2.4 m at the top of next shale horizons. Eclipse 100 simulations are run without and with relative permeability hysteresis in the non-wetting CO_2 phase (Carlson 1981). In cases without hysteresis the drainage relative permeability curves are used in the entire injection period whereas the imbibition relative permeability curves are used in the production period.

A horizontal well in the upper CO_2 plume is needed to drain a significant amount of CO_2. The CO_2 is accumulating in 6 to 8 flat major plumes distributed on top of each other. At present the third plume from the injection point is the largest, but both the time lap seismic and simulations show that the upper plumes are growing fastest while the lower plumes are approaching steady-state. A horizontal production well is therefore placed in the top of the model below the sealing cap rock. The top of the seal has a significant trench (inverted valley) where the well can be placed to minimize water cresting as illustrated in Figure 3.

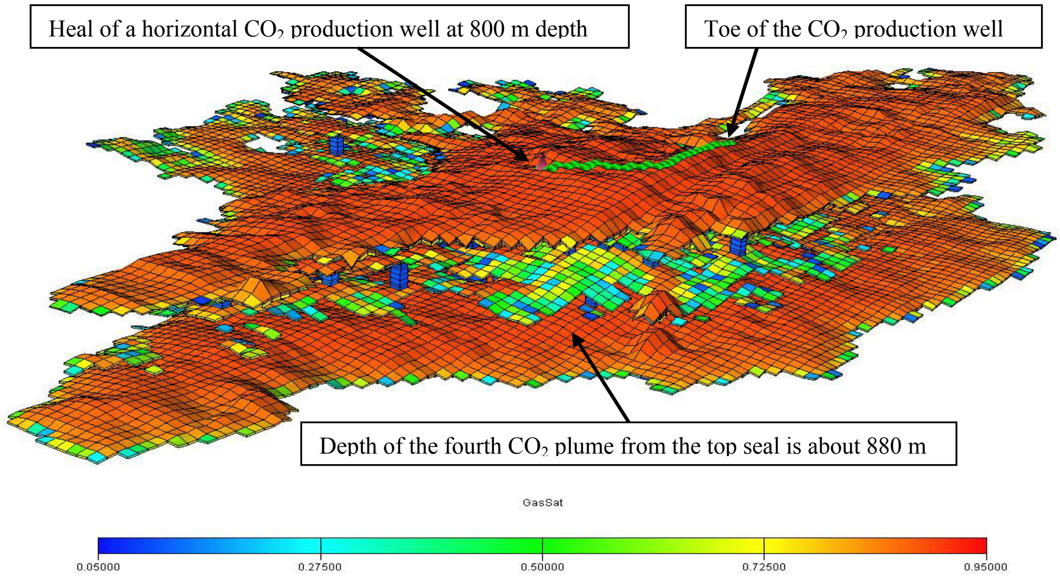

Figure 3 Placement of the CO_2 production well in Utsira at Sleipner (CO_2 saturation shown on color bar; red color high saturation).

The well flowing pressure, the temperature profile and the fluid composition along the entire trajectory of the production well is important for the performance of the well. This was modeled with "lift curves" based on realistic density and phase behavior along the well tube. It was assumed that the production well was a side track on the existing injection well, 15/9 A-16.

4. Results and discussion

The results show that the CO_2 reproduction is in the range of 5.7 - 7.7 Mt, corresponding to 35.2 - 47.7 % of the total injected $CO_{2,}$, during a period of 6 - 8 years provided that a horizontal well can be placed accurately in the upper sand compartment of the formation. The highest yield was found in the case of irreducible water saturation (S_{wi}) at 5 % of the pore volume. The potential for reproducing CO_2 is not very dependent on the production rate.

The injection period is divided into three phases. The first phase starts on September 15, 1996 and continues until November 15, 2004 when 6.5 Mt CO_2 had been injected. For this period historical injection data are used. The second phase starts from November 15, 2004 and injection continues with a constant injection rate of 1.0 Mt/year until January 1, 2008 when the third phase starts with an injection rate of 2.0 Mt/year until January 1, 2011 when the injection is stopped. At this date 16.181 Mt CO_2 had been injected in the scenario. The reproduction period starts when the injection is ended and continues until the production well shuts in when the CO_2 production decreases to below 50 000 Sm^3/day or the well head pressure decreases below 10 bar.

The target CO_2 reproduction rates in the simulations are 0.683 Mt CO_2/year (low rate case) and 1.366 Mt CO_2/year (high rate case). Only 1 % more CO_2 is reproduced in the high rate case compared to the low rate case. The lower residual gas saturation gave 30 % more reproduced CO_2 than for the high residual gas simulations. A short production well (987 m horizontal length) reproduced more CO_2 compared to a 1300 m long well due to less water production before the well is shut in.

The accumulated mass of CO_2 produced in the high rate reproduction cases of $S_{wi} = 0.05$ and 0.15, and low rate CO_2 reproduction for the case of $S_{wi} = 0.15$, all mass in Mt CO_2, are presented in Figure 4. The accumulated mass of produced CO_2 and water in Mt from start to shut-in are presented in **Error! Reference source not found.** all for the case of $S_{wi} = 0.15$ with high and low production rate.

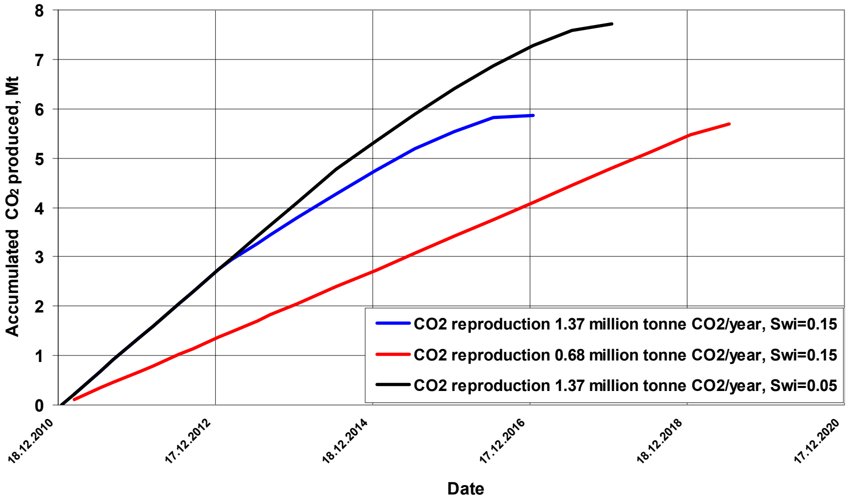

Figure 4 Accumulated CO_2 injection and high and low CO_2 reproduction scenarios.

A 3-D view of the CO_2 saturation in the model at and at January 1, 2013 when water starts cresting into the well for the case of $S_{wi} = 0.05$ are shown in Figure 6. The color bar reflects the CO_2 saturation increasing from blue to red color for higher saturation.

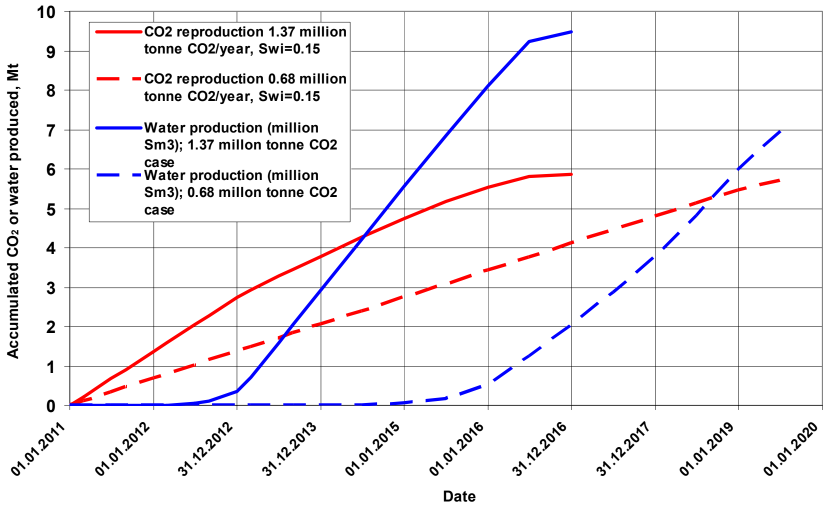

Figure 5 Accumulated production of CO_2 and water for high and low rate cases.

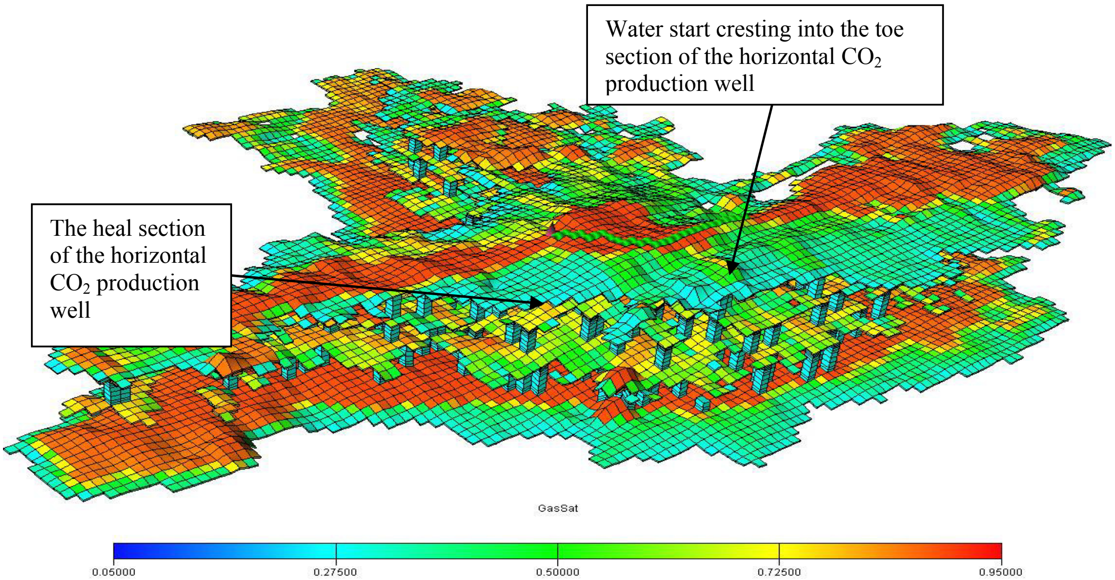

Figure 6 A 3-D view of the CO_2 saturation in the model when water start cresting into the production well in January 01, 2013.

A 3-D view of the CO_2 saturation in the model at and at January 1, 2013 when water starts cresting into the well for the case of $S_{wi} = 0.05$ are shown in Figure 7. The color bar reflects the CO_2 saturation increasing from blue to red color for higher saturation.

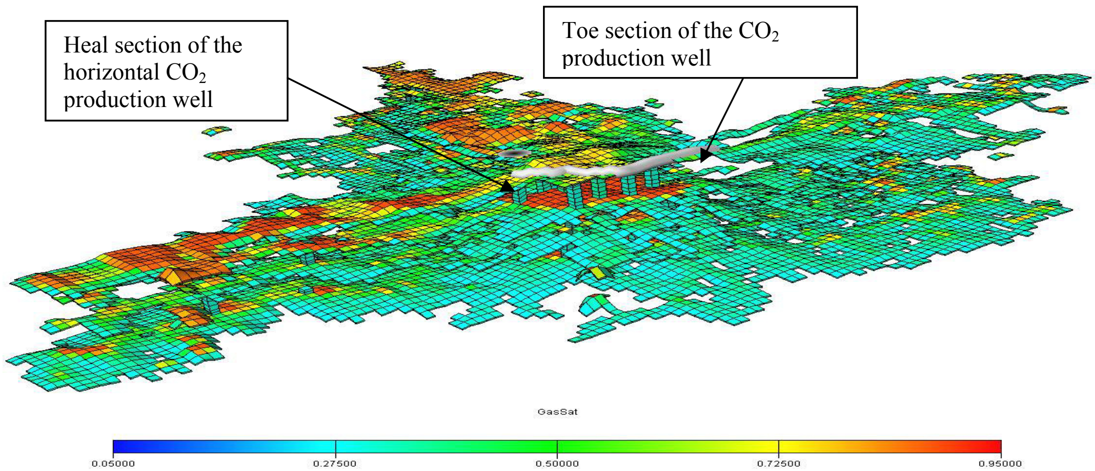

Figure 7 CO_2 saturation in the top layers of the model at well shut-in, July 2017. The production well is shown as a white trajectory.

5. Conclusions

The following conclusions are drawn from the study.

It is feasible to reproduce a part of the injected and stored CO_2 from the Utsira formation at the Sleipner field in the North Sea. Simulation studies were carried out on a scenario where 16 Mt CO_2 had been injected and a part of it reproduced out through a horizontal well in the top of the formation under the seal.

The results show that the CO_2 reproduction is in the range of 5.7 - 7.7 Mt corresponding to the range of 35.2 - 47.7 % of the injected CO_2 during a period of 6 - 8 years.

The result is also an important contribution to the safety aspect of CO_2 storage because it shows that it is feasibly to reproduce CO_2 from a reservoir if it is detected that the seal may not be sufficiently tight for long-term storage.

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